BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-01-43

EXHIBIT NO. 2

GREGORY W. SAID

# Power Cost Adjustment Analysis

Exhibit No. 2
Case No. IPC-E-01-43
G. Said, IPCO
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The Commission, in the 1992 Temporary Rate Increase proceeding, addressed a Power Cost Adjustment (PCA) as follows:

**PCA**

*Several parties to this case urged the Company and Commission to implement some form of mechanism for tracking power supply costs to avoid the need for surcharge cases and to ensure the fair treatment of ratepayers during good as well as poor water years. During cross-examination, Company witness Marshall assured the Commission that Idaho Power was currently studying the feasibility of a PCA and reassessing the Company's position on this issue. In rebuttal testimony, Marshall stated that Idaho Power would submit the results and recommendations regarding its study of PCA to the Commission prior to the filing of its next general rate case. Rebuttal Testimony of J. Marshall, p. 9.*

*We appreciate the comments of the parties on this issue. We never intended the present case to be the forum for ruling on a PCA. We will analyze this issue in a formal proceeding initiated for that purpose or, perhaps, in the course of the Company's next general rate case.*

*The testimony in this case convinces us, however, that there is a compelling need to re-examine the hydrological assumptions upon which IPCo's rates are set. The data underlying those assumptions is almost 10 years old, and, as Mr. Hessing testified, the settlement of the -265 rate case raises questions as to the proper methodology. We therefore advise the Company that if a surcharge application is filed in 1993 a factor in our decision to grant surcharge relief will be the degree of progress achieved in resolving these issues.*

**--------- ORDER NO. 24308, P. 19, ISSUED IN**
**Case No. IPC-E-92-10 -------------**

# Introduction

The revenue requirement and resulting rates for Idaho Power Company include an element referred to as "net power supply expenses." Net power supply expenses are the variable expenses for generating energy to serve customers' loads. The components that have comprised Idaho Power Company's net power supply expenses are fuel (predominately coal) expenses, non-firm purchased power expenses, lost FMC revenues due to interruption of FMC's secondary load, and a credit for surplus sales revenues.

Idaho Power Company's generating facilities consist of 16 hydroelectric facilities (not including Milner) and 3 coal fired thermal facilities. As an investor-owned utility in the United States, Idaho Power Company is unique in that the Company has predominately hydro resources. As such, the net power supply expenses incurred by the Company in any given year are highly related to the volume of stream flows at the hydroelectric generating facilities. When stream flows are high, the Company generates more electricity using water (a near zero cost fuel) at its hydroelectric facilities, and utilizes less of higher cost resources to meet load requirements. Additionally, interruptions of FMC secondary load are less common and energy available for surplus sales is greater. Conversely, when stream flows are low, the Company generates less electricity at its hydroelectric facilities and relies more heavily upon purchased power and thermal generation to meet its load requirements. In addition, FMC interruptibility is more likely to be used as a resource and energy is less likely to be available for surplus sales. The Company's annual net power supply expenses can vary from one condition to another in excess of $100,000,000.

Although the Company's actual net power supply expenses vary from year to year, the Company's rates are based upon an assumed constant level of net power supply expenses. This level has been termed "normalized" net power supply expenses. The normalization of net power supply expenses has been determined, since 1981, by averaging the net power supply expenses associated with a number of water conditions applied to a test year. The method for selecting the water conditions to be included in the averaging process has been widely debated.

Ideally, after rates have been established, net power supply expenses would fluctuate moderately and remain close to the levels used in establishing rates. The last dozen years have been far from this ideal. In the early 1980s, winter snows were heavy and stream flows were high. Beginning in 1987, the current extended drought brought about the opposite extreme, low stream flows. In ten of the last twelve years, the company has experienced extreme water conditions emphasizing that large deviations between actual net power supply expenses and the normalized levels established in revenue requirement proceedings can occur frequently.

## Objective

The primary objective of a Power Cost Adjustment would be to provide a simple and understandable mechanism that would more closely match revenues (resulting from rates) to the actual power supply expenses incurred by the Company. Specifically, that component of a customer's rate which reflects the variable expenses of generating energy to serve the customer's load would be variable and change as the cost of energy changes. As a result, proper and understandable price/cost signals would be sent to the customers. When the Company's net power supply expenses were high, the Power Cost Adjustment would allow for the corresponding rate component to be adjusted to a higher level. Conversely, when the Company's net power supply expenses were lower, the rate component would be lowered. A PCA that conforms to this objective would eliminate recurring disputes concerning power supply expenses that have arisen in the Company's revenue requirement proceedings.

## Components for PCA

The components to be included in a PCA would be those accounts that correspond to the variable expenses for generating energy to serve customers' loads:

1. **Fuel expenses booked to FERC account 501**
2. **Purchased power expenses (including C&SPP) booked to FERC account 555**
3. **Sales for resale (surplus sales) booked to FERC account 447**
4. **Level of FMC secondary load revenues (not booked in a specific FERC account, but discussed below).**

A PCA for Idaho Power Company is complicated by the fact that the Company has a large interruptible load customer (FMC). If the PCA design included only FERC accounts 501, 555, and 447 and ignored FMC secondary revenues, FMC's secondary load would be interrupted to the maximum extent possible to minimize PCA component expenses. However, this design would ignore the potential benefits of the FMC secondary load revenues. If there were no obligation to serve FMC's secondary load, the revenues from that load would be similar to surplus sales revenues on a "when available and the price is right" basis. However, Idaho Power Company does have contractual obligations to FMC. The FMC secondary load is not fully interruptible and as a result, the Company must shepherd its use of FMC interruptibility as a resource.

The solution is to price FMC secondary at an energy rate that encourages the Company to serve the FMC secondary load. The FMC secondary load revenues would then be tracked in a manner similar to surplus sales revenues in a PCA. Adjustments to rates would reflect changes in FMC secondary load revenues. When FMC consumes secondary energy, the system receives benefits from revenues that offset the additional generation expenses. Conversely, when FMC secondary loads are interrupted, the reduced generation expenses are offset by reduced FMC secondary revenues.

## Evaluation of Potential PCA Features

### 1) Bucket Approach

A "bucket" approach is a potential feature of a PCA. The term "bucket" refers to an account in which expenses or revenues are accumulated and deferred until some point in the future when the accumulated expenses or revenues reach the established "capacity" of the bucket. At that time, the bucket is emptied, i.e. the deferred expenses or revenues are amortized and included in the customers' rates. The capacity of the bucket is sometimes referred to as the "trigger", i.e. when the level of accumulated expenses or revenues exceeds the predetermined bucket capacity, a rate adjustment is triggered.

The use of a bucket in a PCA for Idaho Power Company is inconsistent with the stated objective. Rather than adjusting customers' rates to provide revenues that closely match expenses incurred by the Company, a bucket feature defers current expenses or revenues for recovery or reimbursement through rates in a future time period. This feature sends inappropriate price signals to the Company's customers because they pay for current energy at rates that reflect expenses for energy consumed at a prior time. A possible result of a bucket approach might be that the accumulation of expenses triggers a rate increase just before a period of abundant water. Likewise, an accumulation of revenues might trigger a rate decrease to coincide with a period of low water. The Company's customers would be receiving inappropriate price signals.

### 2) Forecast Approach

Another potential PCA feature involves the use of a forecast. Idaho Power

Company, in both its 1988 and 1992 temporary rate increase applications, utilized the National Weather Service River Forecast Center forecast of April through July Brownlee volume inflows to estimate net power supply expenses for the year. As stated in the introduction, there is a strong relationship between stream flow and the Company's net power supply expenses.

Once a normalized level of net power supply expenses has been established in a general revenue requirement proceeding, it is a simple matter to determine an equation for using April through July Brownlee inflows to predict annual net power supply expenses based upon a statistical regression analysis. On April 1 of each year, the National Weather Service makes its final prospective stream flow forecast. Net power supply expenses for the following 12-month period could be estimated at that time and rates could be adjusted to match the forecast.

The use of such a forecast to determine an annual rate adjustment would be consistent with the stated objective for a PCA. Revenues from rates would be adjusted to match the forecasted net power supply expenses to be incurred by the Company. The customer would receive a proper price signal that reflects the costs of energy at the time the customer is consuming and paying for the energy.

**3) True-up**

The use of a forecast suggests a third potential PCA feature that can be referred to as a "true-up." A true-up would be used to correct for any error in the forecast by deferring expenses or revenues as they differ from the forecast. The deferred expenses or revenues would be amortized in the following year with a rate adjustment to coincide with the adjustment for the next 12-month forecast.

A true-up is consistent with the stated objective for a PCA. To the extent that a forecast will not exactly match revenues resulting from rates to expenses incurred by the Company, a true-up involving deferral of expenses or revenues would allow for exact matching. However, because some expenses or revenues would be deferred to the next year, the correct price signal might be dampened.

**4) Band Features**

A fourth potential PCA feature is referred to as a "band." A band is a range of net power supply expenses for which there is no adjustment or only partial adjustment to rates. The inclusion of a band is inconsistent with the stated objective for a PCA in that it identifies a range of expenses for which revenues resulting from rates need not match actual expenses incurred by the Company. The use of a band also suggests that proper price signals are only important when extreme conditions are encountered. The use of a band also fails to remove the dispute in general revenue requirement proceedings as to the appropriate base value for normalized PCA component expenses. Advantages, with regard to PCA component expenses, can be gained by either the customers or the Company by improperly establishing the normalized PCA component expenses reflected in the revenue requirement.

A dispute concerning "fairness" of a PCA with a band could arise when a number of moderately good conditions which fell within the band and required no rate adjustment was followed by a poor condition which fell outside the band and did require rate adjustment. An opposite example of sequenced conditions could also occur. Over time, either the Company or its customers could be advantaged.

**5) In Summary**

Based upon the review of potential PCA features, a PCA that would closely match revenues resulting from rates to the actual expenses incurred by the Company can be designed which would involve annual rate adjustments based on a forecast and a true-up. Other potential features such as buckets, triggers and bands are inconsistent with the stated objective of the PCA. As discussed above, the unique characteristics of the FMC interruptible secondary load, which is both a load and a resource, require special treatment.

# PCA Recommendation

If it is determined that Idaho Power Company should have a Power Cost Adjustment, it is recommended that the PCA be implemented as follows:

An annual adjustment to rates would occur shortly after April 1 based upon an estimate of the projected April 1 through March 31 annual variable cost of providing energy to firm loads. The rates would remain in effect for one year (perhaps May 16 through May 15). Any error in the estimate would be corrected by deferring the actual monthly expenses or revenues as they differ from the estimate. The deferred expenses or revenues would be amortized in the following annual rate adjustment period (again May 16 through May 15 of the following year).

The PCA components of the annual adjustment would be fuel expenses, purchased power expenses, surplus sales revenues and recognition of FMC secondary load revenues. The normalized PCA component values included in the Company's rates would be established by the Commission. Assume, for illustrative purposes, that the Company's rates included the following normalized components:

| | |
|---|---|
| **Account 501-Fuel expense** | **$65,000,000** |
| **Account 555-Purchased Power** | |
| **Non-firm purchased power** | **$ 7,000,000** |
| **C&SPP** | **$23,000,000** |
| **Account 447-Surplus sales** | **$25,000,000** |
| **FMC secondary revenues** | **$16,000,000** |

In order to derive the net expense to serve firm load, it would be appropriate to add the fuel expenses and purchased power expenses associated only with firm load. However, the fuel expense account and purchased power expense account are not separated into firm and non-firm subtotals; fuel expenses and purchased power expenses associated with non-firm loads are included. However, if surplus sales revenues and FMC secondary revenues are considered offsets to the non-firm expenses incurred, the benefit of revenues exceeding expenses will be credited to firm load customers. Using the values set forth in the above illustration, the net expense to serve firm loads is $54 million:

**$65.0 + 7.0 + 23.0 - 25.0 - 16.0 = $54.0 M**

Assuming that the corresponding system firm load was 12,000,000 MWh, the normalized cost of serving firm load would be 4.5 mills per kilowatt hour ($54,000,000/ 12,000,000 MWh).

From the data underlying the determination of the PCA component expenses, a statistical regression that uses April through July Brownlee inflow to predict annual PCA component expense to serve firm load could be derived. For purposes of example, assume that the base annual expense to serve firm load was $115,000,000 and for each acre foot of inflow at Brownlee there was a reduction of $10.5 to the annual expense. The equation to state this would be:

**Annual Expense = $115,000,000 - 10.5 * (Brownlee Inflow).**

The estimated annual expense associated with Brownlee inflow of 5.8 million acre feet would be $54,100,000 (115,000,000 - (10.5 * 5,800,000) ).

On April 1, the National Weather Service River Forecast Center makes its final forecast of that year's April through July Brownlee inflows. This forecast along with the above derived equation, would be used to estimate the subsequent year's annual expense to serve firm load. For example, if the forecast was for 2,000,000 acre feet, the estimated annual expense would be:

**$115, 000, 000 - ( 10 . 5 * 2, 000, 000) = $94, 000, 000**

If the forecast was for 5,800,000 acre feet, the estimated annual expense would be:

**$115,000,000 - (10.5 * 5,800,000) = $54,100,000**

If the forecast was for 9,600,000 acre feet, the estimated annual expense would be:

**$115,000,000 - (10.5 * 9,600,000) = $14,200,000**

The variable cost of serving firm loads under the 3 forecasts would be:

**$94,000,000 / 12,000,000 MWh = 7.8 mills per kilowatt hour**
**$54,100,000 / 12,000,000 MWh = 4.5 mills per kilowatt hour**
**$14,200,000 / 12,000,000 MWh = 1.2 mills per kilowatt hour**

If the Company's rates had included PCA component expenses at the normalized level of 4.5 mills per kilowatt hour, the adjustment to rates based upon these three forecasted estimates would be an increase of 3.3 (7.8 - 4.5) mills per kilowatt hour to the energy component of rates for the first estimate, no adjustment (4.5 - 4.5) for the second estimate, and a decrease of 3.3 (1.2 - 4.5) mills per kilowatt hour to the energy component of rates for the third estimate. The adjustment would be made to the energy portion of the rates charged to firm load customers (again, FMC secondary loads would be considered non-firm and would not be adjusted).

After rates are adjusted to match the forecast of PCA component expenses, the only remaining feature of the PCA would be a "true-up." The true-up would measure deviations of PCA component expenses from the levels included in rates. For example, if the third estimate above (1.2 mills per kilowatt hour) had been the forecast used to adjust rates in a given year, the actual cost of serving firm load still would be calculated for each of the 12 months following the rate adjustment.

For example, actual June costs might be:

| | |
|---|---|
| **Account 501-Fuel expense** | **$3,000,000** |
| **Account 555-Purchased power** | |
| **Non-firm purchased power** | **$ 400,000** |
| **C&SPP** | **$1,400,000** |
| **Account 447-Surplus sales revenue** | **$2,000,000** |
| **FMC secondary revenues** | **$1,000,000** |
| **Actual Firm load** | **1,200,000 MWh** |

The actual cost of serving firm load would be 1.5 mills per kilowatt hour:

$$(3 + 0.4 + 1.4 - 2 - 1) / 1.2 = 1.5 \text{ (000,000 omitted)}$$

or 0.3 mills per kilowatt hour higher than the level included in the rates adjusted for the forecast. This difference between the actual cost and the cost included in rates multiplied by the actual load (1,200,000 MWh) would result in a $360,000 deferral of expenses not recovered through revenues from rates. Each month there would be a similar computation to determine the appropriate level of deferral of expenses or revenues. The accumulation of expense and revenue deferrals would be amortized in the following rate adjustment time period (May 16 through May 15 of the following year).

The price/cost signal that results from the PCA described would be understandable to the Company's customers and would match PCA component revenues to actual power supply expenses incurred by the Company.

## Rate Fluctuations

An indication of potential rate fluctuations resulting from a PCA can be seen by looking at the PCA component expenses over the last ten years. If FMC secondary load revenue benefits were assumed to be 23 m/kwh, the PCA component cost of serving firm loads over the ten year period varies from -3.2 m/kWh to 8.1 m/kWh with the largest one year change in cost being 4.7 m/kWh from 1986 to 1987. The average adjustment would be about 2 m/kWh.

WITH FMC SECONDARY PRICED AT 23 M/KWH

| ACCOUNT NUMBER | DESCRIPTION | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|---|---|---|---|---|
| ADDITIONS: | | | | | | | | | | |
| 501 | FUEL | $ 795.8 | $ 5,602.5 | $ 7,039.9 | $10,925.3 | $10,627.4 | $14,333.7 | $24,969.2 | $38,598.7 | $45,328.5 |
| 555 | PURCHASED POWER | 3,548.0 | 981.0 | 3,707.0 | 25,210.0 | 40,082.0 | 40,689.0 | 29,684.0 | 18,064.0 | 9,273.5 |
| DEDUCTIONS: | | | | | | | | | | |
| 447 | SALES FOR RESALE NONFIRM | 5,759.0 | 12,518.0 | 14,465.6 | 3,031.2 | 36,880.0 | 19,099.9 | 30,983.0 | 33,486.7 | 63,948.2 |
| | FMC SECONDARY | 18,296.0 | 17,846.6 | 17,760.1 | 12,139.6 | 17,129.4 | 12,781.4 | 14,890.0 | 15,832.1 | 17,832.8 |
| TOTAL NET: | PCA COMPONENT EXPENSES | (19,711.7) | (23,781.1) | (21,478.8) | 20,964.5 | (3,300.0) | 23,141.4 | 8,780.2 | 7,344.0 | (27,179.0) |
| TOTAL FIRM LOAD | MWH | 8,345,186 | 8,430,580 | 8,560,114 | 8,996,490 | 9,262,769 | 10,073,174 | 9,864,015 | 10,311,920 | 10,425,337 |
| PCA COMPONENT | M/KWH | (2.362) | (2.821) | (2.509) | 2.330 | (0.356) | 2.297 | 0.890 | 0.712 | (2.607) |
| NET CHANGE: | M/KWH | | (0.459) | 0.312 | 4.839 | (2.687) | 2.654 | (1.407) | (0.178) | (3.319) |

| ACCOUNT NUMBER | DESCRIPTION | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|---|---|---|---|---|
| ADDITIONS: | | | | | | | | | | |
| 501 | FUEL | $44,225.4 | $50,804.5 | $81,819.3 | $31,224.3 | $66,318.9 | $74,499.5 | $77,023.9 | $77,561.4 | $75,134.3 |
| 555 | PURCHASED POWER | 4,457.5 (*) | 2,545.5 (*) | 23,774.1 (*) | 31,849.0 | 30,234.0 | 43,723.0 | 43,845.0 | 43,923.0 | 51,210.0 |
| DEDUCTIONS: | | | | | | | | | | |
| 447 | SALES FOR RESALE NONFIRM | 53,841.9 | 69,121.4 | 79,506.0 | 38,148.6 | 19,189.3 | 11,390.3 | 44,051.2 | 18,578.3 | 11,042.0 |
| | FMC SECONDARY | 18,511.0 | 19,562.2 | 18,210.7 | 17,776.2 | 19,458.0 | 15,251.4 | 17,153.6 | 16,757.4 | 17,924.5 |
| TOTAL NET: | PCA COMPONENT EXPENSES | (23,670.0) | (35,333.6) | 7,876.7 | 7,148.5 | 57,905.6 | 91,580.8 | 59,664.1 | 86,148.7 | 97,377.8 |
| TOTAL FIRM LOAD | MWH | 10,248,323 | 10,880,277 | 11,087,591 | 10,551,833 | 10,761,880 | 11,354,420 | 12,129,640 | 12,098,739 | 12,848,976 |
| PCA COMPONENT | M/KWH | (2.310) | (3.247) | 0.710 | 0.677 | 5.381 | 8.066 | 4.919 | 7.120 | 7.579 |
| NET CHANGE: | M/KWH | 0.297 | (0.938) | 3.958 | (0.033) | 4.703 | 2.685 | (3.147) | 2.202 | 0.458 |

(*) BPA EXCHANGE CREDIT REMOVED FROM ACCOUNT 555 FOR THE YEARS 1982-1985